December 2014

Integrated Financial Forecast (IFF14)

2014/15 - 2033/34

Financial Planning
Finance & Regulatory

Manitoba Hydro

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INTEGRATED FINANCIAL FORECAST (IFF14)

2014/15 – 2033/34

FINANCIAL PLANNING DEPARTMENT
FINANCE & REGULATORY

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INTEGRATED FINANCIAL FORECAST (IFF14)

KEY FINANCIAL RESULTS

(Dollars are in millions)

	Actual	IFF14 Forecast			
	2013/14	2014/15	2015/16	2016/17	2023/24
PROJECTED RATE INCREASES					
- ELECTRIC	3.50%[1]	2.75%[2]	3.95%[3]	3.95%[3]	3.95%
- GAS (non-commodity)	1.07%	-	-	-	1.75%
NET INCOME					
- ELECTRIC	$146	$ 102	$ 115	$ 59	($124)
- GAS	20	7	4	0	4
- SUBSIDIARIES	8	6	6	7	11
CAPITAL EXPENDITURES					
- ELECTRIC	$ 1 348	$ 2 023	$ 2 491	$ 3 073	$ 681
- GAS	35	48	65	51	43
DEBT/EQUITY RATIO	76:24	77:23	81:19	83:17	89:11
INTEREST COVERAGE RATIO	1.28	1.17	1.17	1.07	0.92
CAPITAL COVERAGE RATIO (excl. major new generation & transmission)	1.35	0.99	1.05	0.96	1.24
RETAINED EARNINGS	$2 716	$ 2 831	$ 2 901	$ 2 968	$2 226

[1] The 3.5% rate increase was implemented effective May 1, 2013. In accordance with PUB Order 43/13, 1.5% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.

[2] The interim 2.75% rate increase was implemented effective May 1, 2014. In accordance with PUB Order 49/14, 0.75% of the rate increase will be accrued to a deferral account to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service.

[3] The proposed 3.95% rate increases would be effective April 1, 2015 and April 1, 2016.

EXECUTIVE SUMMARY

The Consolidated Integrated Financial Forecast (IFF14) projects Manitoba Hydro's financial results and financial position for the 20-year period from 2014/15 to 2033/34. Segmented forecasts are also provided for the electricity (MH14), natural gas (CGM14), and corporate subsidiaries (CS14).

The key changes to the financial outlook in IFF14 are as follows:

- Lower general consumers revenue ($3.3 billion) due mainly to increased demand side management savings, a lower approved rate increase for 2014/15 and lower projected indicative rate increases from 2031/32 to 2033/34.

- Lower projected net extraprovincial revenues ($2.0 billion) due mainly to the suspension of Conawapa, as well as lower projected export prices, partially offset by increased energy available for export as a result of increased demand side management (DSM) energy and capacity savings;

- Lower projected capital expenditure forecast ($7.5 billion) mainly due to the suspension of Conawapa ($10.1 billion) and the deferral of Pointe du Bois Powerhouse Rebuild ($1.5 billion). This decrease is partially offset by higher projected capital costs for sustaining capital ($1.9 billion), Bipole III ($1.3 billion), DSM ($0.9 billion), and Keeyask ($0.3 billion).

- Lower finance expense ($2.6 billion) and depreciation expense (down $0.2 billion) that result from lower projected interest rates, reductions in depreciation rates as recommended in the updated depreciation study, and the suspension of Conawapa. These decreases are partially offset by the higher projected capital costs for sustaining capital, Bipole III, DSM, and Keeyask.

In the near term to 2017/18, net income is higher compared to IFF13, largely due to favourable water flow conditions and lower finance and depreciation expenses. However, there are lower net earnings projected in the remaining years of IFF14 due to the key changes noted above. The projected net losses between 2018/19 to 2025/26 largely reflect the significant increase in carrying costs associated with Bipole III, sustaining capital expenditures and Keeyask which will essentially double the net plant of the Corporation. After that period, the higher export revenues associated with Keeyask and cumulative domestic rate increases return the Corporation to profitability.

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of the planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by the Fall of 2016).

Manitoba Hydro continues to project minimum indicative rate increases of 3.95% per year in IFF14 to 2030/31 and then 2.00% thereafter to 2033/34. In order to maintain the 3.95% rate increases in the near to medium term, Manitoba Hydro continues to pursue further cost containment initiatives and the deferral or cancellation of a number of capital projects. Should a severe drought occur during the first 10-year period, net income and the equity ratio would be further challenged and higher rate increases would be necessary.

Consistent with IFF13, the equity ratio is projected to deteriorate from the current 24% level to 11% equity by 2022/23 before gradually beginning to recover to reach the 25% equity target by 2033/34. There is no change in attaining the 25% equity target compared to IFF13.

The other key financial targets – interest coverage and capital coverage – are also below target for several years but recover to the target range within the later years of the 20 year forecast.

The major factors contributing to the need for the 3.95% rate increases are the expenditures that are necessary to meet the growing electricity requirements of the Province and the requirement to replace distribution, transmission and substation assets that were installed up to 60 years ago. The aging infrastructure issue is facing all utilities in North America and is resulting in considerably higher rate increases than are being projected in Manitoba. For this reason, even with the rate increases being projected in IFF14, it is expected that Manitoba's domestic electricity customers will continue to have rates that are affordable and competitive with other utilities in North America.

The following is a summary of projected net income and key financial ratios over the 20-year period to 2033/34:

Years Ending March 31	Electric Rate Increases	Net Income	Retained Earnings	Debt / Equity	Interest Coverage	Capital Coverage
		(Millions)				
2015	-	$115	$2,831	77:23	1.17	0.99
2016	3.95%	126	2,901	81:19	1.17	1.05
2017	3.95%	67	2,968	83:17	1.07	0.96
2018	3.95%	75	3,043	84:16	1.07	1.13
2019	3.95%	(75)	2,968	85:15	0.94	0.94
2020	3.95%	(102)	2,866	86:14	0.92	0.86
2021	3.95%	(164)	2,702	87:13	0.88	0.87
2022	3.95%	(192)	2,510	88:12	0.86	0.98
2023	3.95%	(174)	2,336	89:11	0.87	1.11
2024	3.95%	(109)	2,226	89:11	0.92	1.24
2025	3.95%	(38)	2,188	89:11	0.97	1.27
2026	3.95%	(9)	2,179	89:11	0.99	1.31
2027	3.95%	97	2,276	88:12	1.07	1.47
2028	3.95%	168	2,444	87:13	1.12	1.57
2029	3.95%	279	2,724	86:14	1.20	1.68
2030	3.95%	415	3,139	84:16	1.30	1.91
2031	3.95%	551	3,690	82:18	1.41	1.99
2032	2.00%	662	4,352	79:21	1.52	2.14
2033	2.00%	741	5,093	76:24	1.60	2.22
2034	2.00%	842	5,935	73:27	1.70	2.34

Section 1

1.0 INTRODUCTION

The Consolidated Integrated Financial Forecast (IFF14) provides projections of Manitoba Hydro's financial results and financial position for the 20-year period from 2014/15 to 2033/34. Its purpose is to project the Corporation's long-term financial direction. The detailed forecasts in the first two years of the IFF are used for monthly reporting and variance analysis. The IFF serves as the primary forecast to determine the need for rate increases that are necessary for the Corporation to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets.

The forecast is the culmination of an extensive integrated planning cycle at Manitoba Hydro. It is based on the best available information at the time it is prepared and includes forward looking information that incorporates expectations, estimates and assumptions concerning the future which are subject to change. Key inputs to the Integrated Financial Forecast include:

- Economic Outlook
- Energy Price Outlook
- Electricity Export Price Forecast
- Power Smart Plan
- Electric Load Forecast
- Natural Gas Volume Forecast
- Domestic Revenue Forecast
- Power Resource Plan
- Generation Costs and Interchange Revenue Forecast
- Capital Expenditure Forecast
- Operating, Maintenance & Administrative Expense Forecast

This forecast supersedes the 2013 Integrated Financial Forecast (IFF13) which was finalized in February of 2014.

2.0 RATES and ECONOMIC VARIABLES

2.1 Electricity Rates

In accordance with Manitoba Public Utilities Board (PUB) Order 49/14, IFF14 includes an interim 2.00% rate increase effective May 1, 2014 for revenues directed to General Consumers Revenue with a further 0.75% for revenues directed to the Bipole III Deferral Account. The Bipole III Deferral Account was established in PUB Order 43/13 to be utilized to mitigate the anticipated rate impact when Bipole III is placed in-service. IFF14 assumes that the revenues accumulated in the Bipole III Deferral Account will be drawn down over a 3-year period following the Bipole III in-service (July 2018) and that cumulative rate increases applied to the Bipole III Deferral Account will revert to general consumers revenue thereafter.

IFF14 proposes additional rate increases of 3.95% effective April 1 in each of 2015 and 2016. The April 1, 2015 rate increase will be requested on an interim basis to be finalized by the PUB in the 2015 General Rate Application. Indicative additional average annual electric rate increases of 3.95% are projected each April from 2017/18 through 2030/31 and then 2.00% from 2031/32 to 2033/34.

The rate increases proposed for 2015/16 and 2016/17 have been approved by the Manitoba Hydro-Electric Board (MHEB) for submission to the PUB. Proposed rate increases subsequent to 2017/18 may be changed in future forecasts and are presented for illustrative purposes only. Each year's revision to the Integrated Financial Forecast is based on the current year's assumptions including energy supply and demand, projected interest, escalation and exchange rates, projected prices for exported energy, operating and capital forecasts and other factors. Changes in any of these assumptions will have an impact on the projected future results. Actual rate applications made in future years will depend upon the circumstances and outlook at that time and will be subject to the review and approval of the MHEB.

2.2 Gas Rates

Manitoba Hydro does not propose any non-gas rate changes for 2014/15 through 2016/17. Thereafter, IFF14 assumes non-gas rate increases as required to generate Centra Gas net income of approximately $3 million each year. Gas general rate applications are also subject to review and approval by the MHEB prior to filing with the PUB.

2.3 Economic Variables

The economic assumptions used in the forecast are based upon Manitoba Hydro's Economic Outlook, with certain key variables updated as of October 2014 to reflect current economic conditions at that time. Projected rates for key economic indicators are listed below with the 2013 projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	US-CDN Exchange Rate (C$/US$)
2014/15	1.8% (2.0%)	0.95% (1.15%)	3.50% (4.05%)	1.10 (1.03)
2015/16	1.9% (2.0%)	1.30% (2.10%)	4.10% (4.35%)	1.12 (1.01)
2016/17	2.0% (2.0%)	2.40% (3.10%)	4.50% (4.60%)	1.12 (1.01)
2017/18	2.0% (2.0%)	3.10% (3.70%)	4.80% (5.40%)	1.12 (1.03)
2023/24	2.1% (2.0%)	3.90% (3.90%)	5.20% (5.75%)	1.10 (1.03)

* Excludes the 1% Provincial guarantee fee.

The forecasts of US-CDN exchange rates and interest rates have been decreased since the fall 2013 forecasts. The major factors influencing the drop in the forecast of US-CDN exchange rates is due to lower oil price projections and differing expectations with respect to Canadian and US monetary policy and growth. With the actual interest rates for the first three quarters of 2014 resulting in materially lower outcomes than what was forecasted and with the Bank of Canada's commitment to maintain short-term interest rates at near low levels, the updated lower starting point and gradual progression has resulted in lower interest rate forecasts. Forecasters now generally expect the Bank of Canada to hold off on raising interest rates to at least mid 2015 with the overall consensus being that the long-term rate will be lower than the pre-recession period.

3.0 MANITOBA ELECTRICITY LOAD FORECAST

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2014 Electric Load Forecast. The Load Forecast includes demand side management savings achieved to date as well as projected savings achieved through codes and standards. Planned additional savings are incorporated in the forecast of general consumers revenue separately from the Load Forecast and are discussed in Section 4.0 below.

The 2014 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.8% for gross firm energy and 1.6% for gross total peak over the 10-year forecast period to 2023/24 (compared to 1.4% for both in IFF13). Gross firm energy supplied to the Manitoba load is projected to grow from 25 639 GW.h in 2014/15 to 29 626 GW.h by 2023/24. Over the same 10-year period, total system peak is projected to grow from 4 716 MW in 2014/15 to 5 400 MW in 2023/24. The 20-year average growth is expected to slow to 1.5% for gross firm energy and 1.3% for gross total peak by 2033/34. The system load factor is projected to remain relatively constant between approximately 62% and 63%.

Compared to the 2013 forecast, gross firm energy is projected to be up 614 GW.h (nearly 1½ year's load growth) by 2023/24 primarily due to increases in the pipeline sector as well as increases in the mass market sector due to a higher residential customer forecast in the short term. Over the longer term, the increase in gross firm energy is expected to be reduced to 129 GW.h (less than half a year's load growth) by 2032/33 due to a lower residential customer forecast in the longer term and an increase in the projected impacts of codes and standards. The gross total peak forecast is 104 MW higher in 2023/24 and 28 MW lower than the 2013 forecast in 2032/33, for similar reasons as the change in energy.

Over the 20-year forecast period, the impact of the change in the load forecast compared to IFF13 (before energy and capacity savings from incremental DSM) is minimal.

4.0 DEMAND SIDE MANAGEMENT

IFF14 incorporates the demand side management domestic customer energy and demand savings and investments forecast in the 2014-2017 Power Smart Plan and 15 year supplemental forecast. The Power Smart Plan, endorsed by the Province of Manitoba, sets out to realize electricity savings of 1 136 MW and 3 978 GW.h, natural gas savings of 108 million cubic meters and combined global greenhouse gas emission reductions of 2.9 million tonnes by 2028/29. This activity represents 12.7% of the estimated electric load forecast offsetting 66% of projected load growth during this period and 5.3% of the estimated natural gas volume forecast by 2028/29, further reducing natural gas consumption in Manitoba.

Combined with energy savings achieved to date, total electrical savings of 1 635 MW and 6 286 GW.h and total natural gas savings of 211 million cubic meters will be realized by 2028/29. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 4.6 million tonnes by 2028/29. This activity represents 20.1% of the estimated electric load forecast and 10.2% of the estimated natural gas volume forecast by 2028/29.

The projected cost of demand side management included in IFF14 is $1.2 billion over the 20-year period to 2033/34 or $0.9 billion greater than IFF13.

Overall, the forecast of General Consumers Revenue in IFF14 is $3.3 billion lower compared to IFF13 due mainly to the projected energy and capacity savings resulting from DSM as well as the lower rate increase approved for 2014/15 and lower projected indicative rate increases from 2031/32 to 2033/34.

5.0 EXTRA-PROVINCIAL REVENUE

IFF14 includes the following long-term firm export sales:

Northern States Power 150 MW Seasonal Diversity	To April 2015
Northern States Power 200 MW Seasonal Diversity	To April 2016
Northern States Power 500 MW Power Sale	To April 2014
Minnesota Power 50 MW System Participation Sale	May 2009 to April 2015
Minnesota Power 50 MW System Participation Sale	May 2015 to May 2020
Minnesota Power 250 MW System Participation Sale	June 2020 to May 2035
Great River Energy 150 MW Seasonal Diversity Sale	May 1995 to April 2015
Great River Energy 200 MW Seasonal Diversity Sale	May 2015 to March 2030
Northern States Power 125 MW System Power Sale	May 2021 to April 2025
Northern States Power 375/325 MW System Power Sale	May 2015 to April 2025
Northern States Power 350 MW Seasonal Diversity Sale	May 2015 to April 2025
Wisconsin Public Service 100 MW Sale	June 2021 to May 2027
Wisconsin Public Service 108 MW System Participation	June 2014 to May 2021
SaskPower 25 MW System Participation Sale	November 2015 to May 2022
American Electric Power 50 MW ZRC	May 2016 to May 2018
NextEra 10 MW Sale	June 2014 May 2015
NextEra 40 MW Sale	June 2015 to May 2016
NextEra 100 MW Sale	June 2016 to May 2018

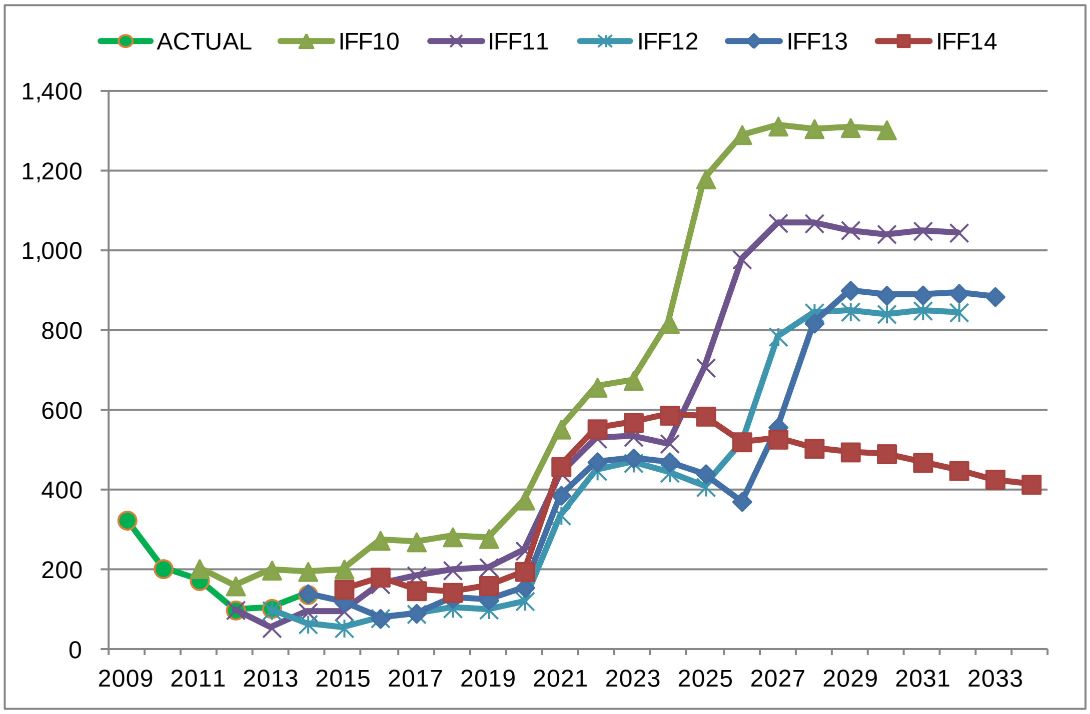
Extra-provincial sales volumes are forecast for the first forecast year (2014/15) based upon the expected inflow conditions as of October 2014 and actual reservoir and lake level elevations as of September 2014. The second forecast year (2015/16) uses the median of 80 years of historic inflows and initial reservoir and lake level elevations carried forward from the 2014/15 forecast. For 2016/17 and subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 102 years (1912/13 to 2013/14).

Over the 20-year forecast period, net extra-provincial revenue (extra-provincial revenue net of water rentals and fuel and power purchased) decreases $2.0 billion compared to IFF13. The decrease is mainly due to the suspension of Conawapa in IFF14 as well as slightly lower forecasted export prices. This decrease is partially offset by higher volumes of energy available for export as a result of a reduction in the Manitoba domestic load forecast through increased DSM programs and higher forecasted US-CDN exchange rates.

The following Figure 5-1 shows the comparative net extra-provincial revenues from IFF10 through IFF14.

Figure 5-1: Extra-provincial Revenues

(Net of Water Rentals and Fuel and Power Purchases)



In comparison to the 2013 Electric Export Price Forecast, the 2014 forecast projects prices for a long term dependable electricity product will be, on average, 7% lower over the period 2016/17 to 2035/36. Over that time horizon energy prices (both on and off peak) are forecast to be an average of 3% lower with the value of capacity down 15% relative to the 2013 outlook. The decrease reflects the forecast for lower natural gas prices, with a minor offset due to the stabilizing effects of relatively flat year over year coal and carbon price forecasts, along with some additional clarity on US environmental regulation and resulting coal fleet retirements.

6.0 ELECTRICITY SUPPLY

Manitoba Hydro's 2014/15 Power Resource Plan indicates new generation is required by 2038/39 to meet the current projection of Manitoba load requirements under dependable energy conditions. New capacity resources are forecast to be required by 2037/38.

The following resources contribute to the ability to meet future Manitoba energy and capacity requirements.

	MW	Dependable GW.h	In-Service Date
HVDC Bipole III Line & 2300 MW of Converter Capability	80	177	2018/19
Keeyask	695	3 000	2019/20
Demand Side Management Program			
Planned Additional	582	2 797	By 2028/29

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by the Fall of 2016).

7.0 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February of 2013, the Canadian Accounting Standards Board (AcSB) extended the optional IFRS transition date for rate-regulated entities an additional year to January 1, 2015 in consideration of the commitment of the International Accounting Standards Board (IASB) to review issues related to rate-regulated accounting. Manitoba Hydro has adopted the optional transition date deferral and will be transitioning to IFRS effective April 1, 2015 for its 2015/16 fiscal period with comparative information presented for 2014/15.

On January 30, 2014, the IASB issued a new interim standard IFRS 14 Regulatory Deferral Accounts which is effective January 1, 2016 with early adoption permitted. The interim standard allows rate-regulated entities to continue to recognize regulatory deferral accounts (i.e. regulatory assets and liabilities) upon transition to IFRS. The intent of the standard is to provide temporary guidance until the IASB completes its comprehensive project on Rate-regulated Activities which is expected to take several years.

Manitoba Hydro will early adopt IFRS 14 upon its April 1, 2015 transition and as such, will continue to recognize its regulated assets and liabilities upon transition to IFRS. While it is uncertain as to the final position the IASB will take as part of its comprehensive Rate-regulated Activities project, it has been assumed in IFF14 that regulatory deferral accounts will continue to be recognized throughout the forecast period to 2033/34.

Generally speaking, the transition to IFRS will result in timing differences between when expenditures are recognized into income between Canadian Generally Accepted Accounting Principles (CGAAP) and IFRS. Manitoba Hydro recognizes that the different financial reporting requirements under IFRS will both increase and decrease annual net income. As such, Manitoba Hydro has considered the range of potential impacts and where possible, has selected accounting policies aimed at minimizing the overall impact to net income and customer rates.

The primary impacts of IFRS that are included in IFF14 are as follows:

- Administrative and other general overhead costs are not eligible for capitalization under IFRS and must be expensed as incurred;
- IFRS is more rigorous in terms of the componentization of assets and the recognition of gains and losses on the disposal/retirement of assets and does not allow the inclusion of asset retirement costs in depreciation rates; and
- Unamortized experience gains and losses on pension balances will be reclassified to accumulated other comprehensive income (AOCI) upon transition to IFRS.

The following table Figure 7-1 outlines the projected IFRS impacts to retained earnings, AOCI and net income:

Figure 7-1: IFRS Impacts on Retained Earnings and Net Income

IFRS Impacts
Increase/(Decrease)

($Millions)

	Retained Earnings	AOCI	Net Income 2015/16
Capital Taxes	-	-	3
Administrative Overhead	(56)	-	(57) *
Pension & Employee Benefits	(24)	(445)	3
Meter Compliance, Exchange and Sampling	-	-	5
Removal of Negative Salvage	62	-	64
Change to Equal Life Group Depreciation	(36)	-	(38)
Total	**(54)**	**(445)**	**(20)**

*Impacts to net income are net of depreciation & amortization.

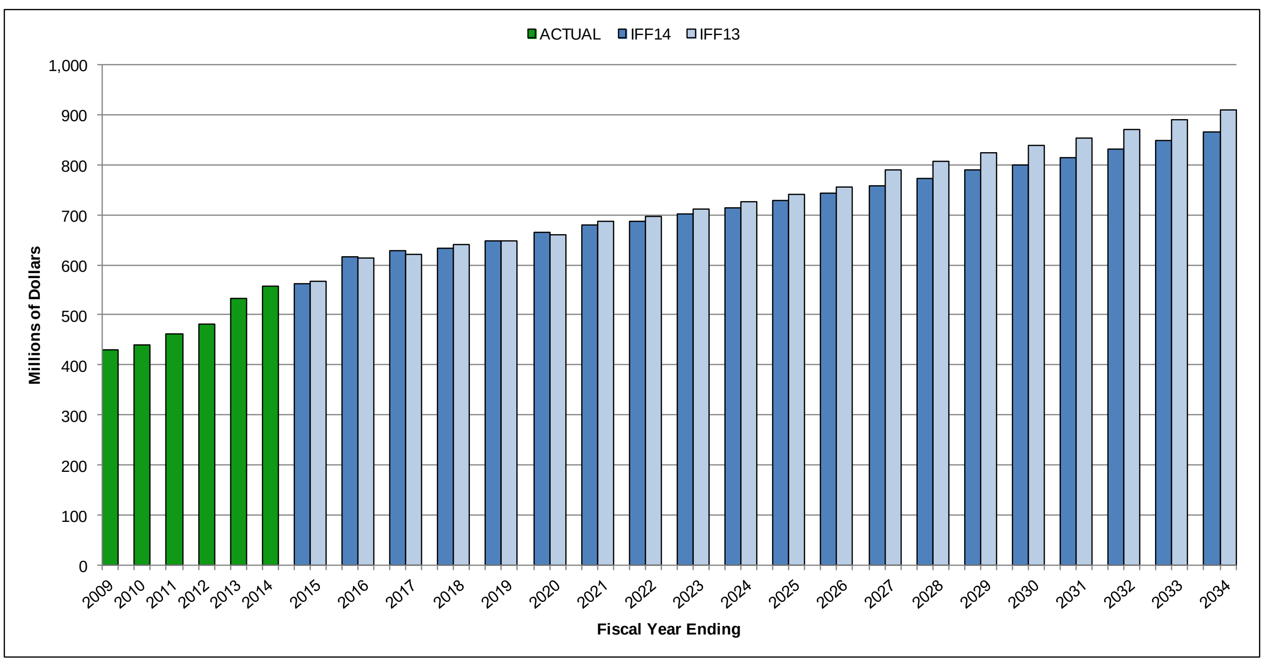
8.0 OPERATING & ADMINISTRATIVE EXPENSE

Operating, Maintenance & Administrative (OM&A) Expenses in IFF14 include only those expenditures necessary to provide for the safe and reliable operation and maintenance of the generation, transmission and electric and gas distribution systems.

Figure 8-1 below shows the OM&A expense projected in IFF14 compared to IFF13. On an overall basis, OM&A remains relatively unchanged from IFF13. IFRS adjustments remain in place beginning 2015/16 and more aggressive cost containment measures continue to be implemented to keep costs below inflationary levels. Reductions in the later years are due to a reclassification of Great Northern Transmission Line costs to Fuel and Power Purchases for IFF14, as well, as the deferral of Bipole III for one year and suspension of Conawapa.

For the period from 2014/15 to 2021/22, it is assumed that OM&A cost increases, excluding accounting changes, will be limited to below inflationary levels of 1%. This is an advancement of one year compared to IFF13 which assumed the 1% escalation commenced in 2015/16. For the remainder of the forecast, OM&A rises at the same level as inflation except in years where major new generation and transmission comes into service in 2018/19 (Bipole III), 2019/20 (Keeyask) and 2020/21 (500kV tie line). Increases associated with load growth over the forecast period are assumed to be achieved through continuing productivity improvements.

Figure 8-1: Operating, Maintenance and Administrative Expense

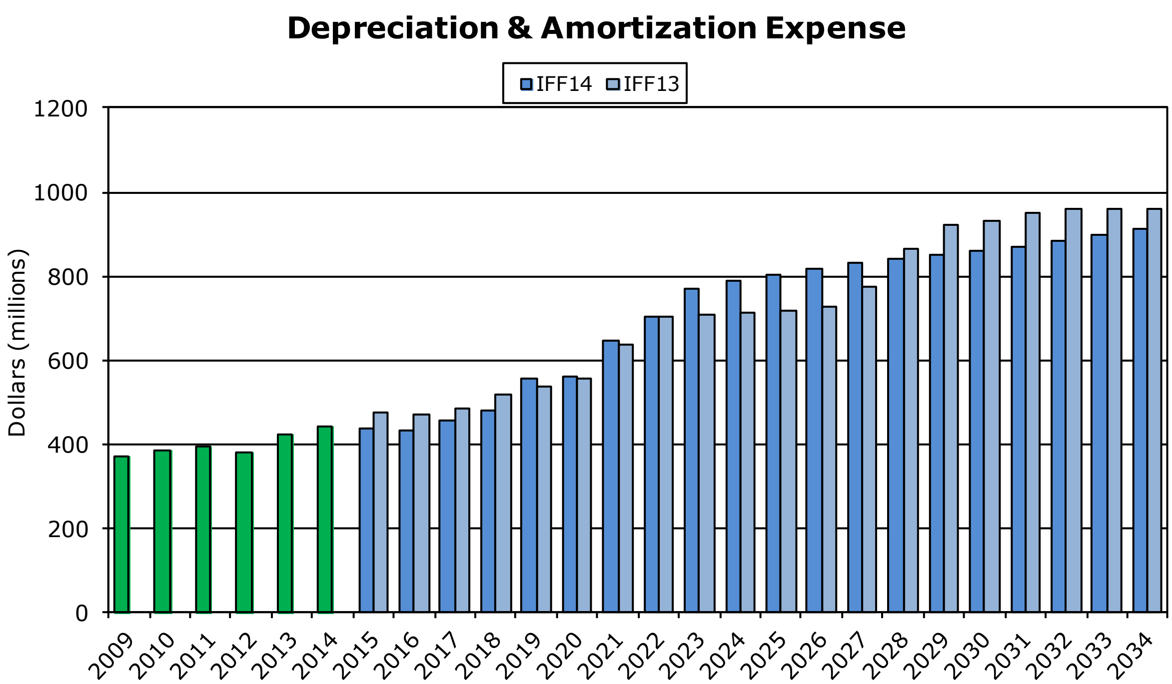


9.0 DEPRECIATION & AMORTIZATION EXPENSE

The Depreciation and Amortization Expense included in IFF14 is based on a comprehensive depreciation study that was completed in October 2014.

Figure 9-1 below provides a comparison of the Depreciation and Amortization Expense between IFF14 and IFF13. Depreciation and Amortization Expense is $0.2 billion lower in IFF14 over the 20-year forecast period compared to IFF13 primarily due to the reduction in depreciation rates resulting from updated asset service lives as recommended in the depreciation study (decrease of $0.9 billiion), as well as the suspension of Conawapa (decrease of $0.9 billion). This reduction is largely offset by the higher capital costs of Bipole III, DSM and Major and Base Capital Expenditures (increase of $1.5 billion).

Figure 9-1: Depreciation and Amortization Expense



10.0 WUSKWATIM POWER LIMITED PARTNERSHIP

IFF14 assumes that the Nisichawayasihk Cree Nation (NCN) will acquire up to a 33% common unit ownership interest in the Wuskwatim Power Limited Partnership (WPLP). The WPLP will operate and maintain the Wuskwatim generating station and Manitoba Hydro will purchase all of the generation under the terms of the Wuskwatim Project Development Agreement (PDA) signed by Manitoba Hydro and NCN in 2006. Manitoba Hydro's income statement reflects all of the partnership revenues and costs with non-controlling interest representing NCN's share of the projected net income or losses in WPLP (shown as a deduction or addition before net income, respectively). The partnership's net assets are offset by an amount for NCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

During 2014, Manitoba Hydro and NCN reached an agreement in principle with respect to Wuskwatim PDA Supplement #2. IFF14 assumes the terms of the agreement in principle commencing in 2014/15. The projected net impact to Manitoba Hydro averages approximately $15 million per year over the 20-year forecast period.

It is expected that the agreement in principle will be finalized into a legally binding agreement over the next several months.

11.0 KEEYASK HYDROPOWER LIMITED PARTNERSHIP

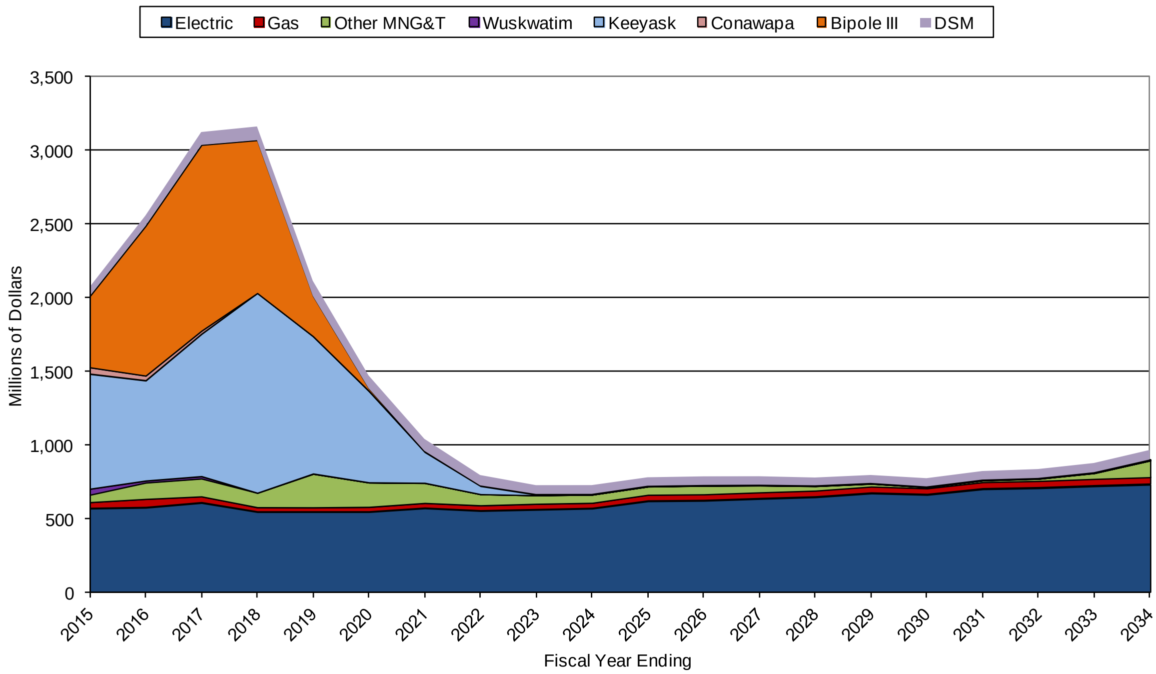
The Keeyask Cree Nations (KCN's), including Tataskweyak Cree Nation and War Lake First Nation (operating together as Cree Nation Partners), Fox Lake Cree Nation and York Factory First Nation, have the right to acquire up to 25% in the Keeyask Hydropower Limited Partnership (KHLP). The partnership will construct, operate and maintain the Keeyask generating station and Manitoba Hydro will purchase all of the generation under the terms of the Joint Keeyask Development Agreement (JKDA) signed by Manitoba Hydro and the KCN's in 2009. Manitoba Hydro's income statement reflects all of the partnership revenues and costs. The partnership's net assets are offset by an amount for the KCN's non-controlling equity interest on Manitoba Hydro's balance sheet.

IFF14 assumes the KCN's will hold a 17.5% common ownership interest up to the in-service of the final Keeyask generating unit and then elect to invest in the preferred ownership option. The preferred distributions to the KCN's have been reclassified as an expense (fuel & power purchases) in IFF14 from non-controlling interest in previous forecasts.

12.0 CAPITAL EXPENDITURE FORECAST

Capital expenditures are forecast to be $17.8 billion to 2023/24 and $26.0 billion to 2033/34. Figure 12-1 below illustrates projected capital expenditures by major category.

Figure 12-1: Capital Expenditure Forecast CEF14



The CEF14 includes Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability. In August 2013, the Province of Manitoba issued an Environmental Act licence for the Bipole III Reliability project and construction has commenced with a planned in-service date of 2018/19. In July 2014 the Province of Manitoba issued an Environmental Act licence for the Keeyask Generating Station and construction has commenced with a planned in-service date of 2019/20. Manitoba Hydro continues to develop the Manitoba-Minnesota Transmission Project, a transmission interconnection into the U.S. which supports enhanced export capability, reliability and drought risk mitigation. The Province also endorsed Manitoba Hydro's new, more aggressive demand side management PowerSmart plan which targets a 250% increase in consumption savings.

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by Fall 2016).

Over the 10-year forecast to 2023/24, capital expenditures are $3.4 billion lower compared to the previous capital expenditure forecast (CEF13). The decrease is mainly due to the suspension of Conawapa. In addition, reductions have been identified for the Gillam Redevelopment and Expansion program, deferral of the Slave Falls Overhaul project, and the cancellation of the Dorsey 230 kV Zone Building and Firm Import Upgrades projects. These decreases in the 10-year forecast period are partially offset by increases in sustaining capital expenditures and DSM expenditures as well as Bipole III and Keeyask projects.

Over the longer term to 2033/34, capital expenditures are $7.5 billion lower compared to CEF13 due to the suspension of Conawapa and deferral of the Pointe du Bois Powerhouse Rebuild project. The decrease is partially offset by increased expenditures for sustaining infrastructure, Bipole III, DSM and Keeyask as previously indicated for the 10-year period.

The following Table 12-1 provides a summary of CEF14 and the revisions from CEF13.

Table 12-1: Summary of Projected Capital Expenditures

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	2,062	2,483	2,543	2,358	2,061	1,878	1,372	1,755	2,319	2,359	21,191
Incr (Decr)	9	73	580	803	52	(408)	(333)	(962)	(1,595)	(1,635)	(3,416)
CEF14	2,071	2,556	3,124	3,161	2,113	1,470	1,039	793	724	724	17,774

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
CEF13	2,162	2,048	1,838	1,399	1,098	922	828	680	630	679	33,474
Incr (Decr)	(1,384)	(1,264)	(1,054)	(623)	(305)	(151)	(8)	154	245	285	(7,521)
CEF14	778	784	785	776	793	771	820	834	875	963	25,953

The following Table 12-2 provides a summary of the total changes to the 10 and 20-year forecast.

Table 12-2: Summary of CEF14 Project Increases/(Decreases)

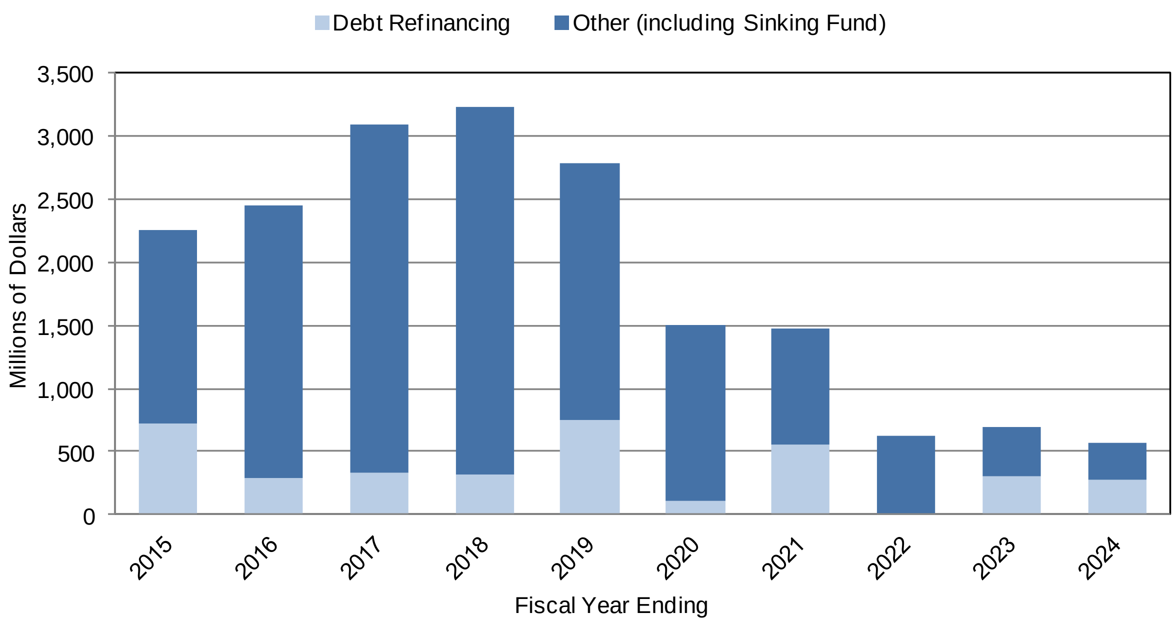
	Total Projected Cost	10 Year Increase (Decrease)	20 Year Increase (Decrease)
	($ Millions)		
Conawapa - Generation	397	(6,052)	(10,065)
Base Capital Target	NA	422	1,957
Pointe du Bois Powerhouse Rebuild	1,852	(19)	(1,471)
Bipole III - Converter Stations	2,675	881	881
Demand Side Management *	NA	463	802
Additional North South Trasmission	-	(90)	(475)
Bipole III - Transmission Line	1,655	407	407
Keeyask - Generation	6,496	349	349
Gillam Redevelopment and Expansion Program	266	(77)	(100)
Gas Demand Side Management *	NA	50	92
Bipole III - Collector Lines	260	71	71
Dorsey 230KV Zone Building	-	(63)	(63)
New Adelaide Station - 66/12kV	62	62	62
Slave Falls Major Overhauls	126	(63)	-
Other System Upgrades		243	32
		(3,416)	(7,521)

* Assumes that Demand Side Management expenditures will continue to be capitalized upon adoption of IFRS in 2015/16 under the interim standard that continues to permit rate regulated accounting.

13.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast consolidated borrowing requirements are portrayed in Figure 13-1 below.

Figure 13-1: Projected Consolidated Borrowing Requirements



Manitoba Hydro arranges long-term financing in the form of advances from the Province of Manitoba. Both long and short-term borrowings are guaranteed by the Province (except for mitigation bonds issued by the Manitoba Hydro-Electric Board). Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; to a maximum of 35% of the total debt portfolio. Manitoba Hydro's interest rate risk guidelines for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio.

14.0 NATURAL GAS DEMAND & SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 94% of customers representing approximately 62% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The volume forecast incorporates Manitoba Hydro’s Fixed Price Offering for primary gas, which was introduced in 2008/09 and offers customers one, three, and five-year fixed price contracts.

The forecast incorporates the transportation and supplementary gas requirements, not only for Manitoba Hydro’s customers but also for those consumers who purchase their primary gas from brokers and marketers.

The total natural gas sales volume forecast decreases 40 million cubic meters (1.9%) from 2013/14 to 2014/15 and continues to decrease by 6.5 million cubic meters (0.3% per year) to 2023/24. The decrease is primarily attributed to a change in the expected average use across all customer sectors, by reducing their non-process related natural gas usage due to conversions to high efficiency furnaces, improvements in insulation levels and conversion of Residential sector from natural gas to electric water heaters.

15.0 FINANCIAL TARGETS

Manitoba Hydro has the following financial targets for consolidated operations:

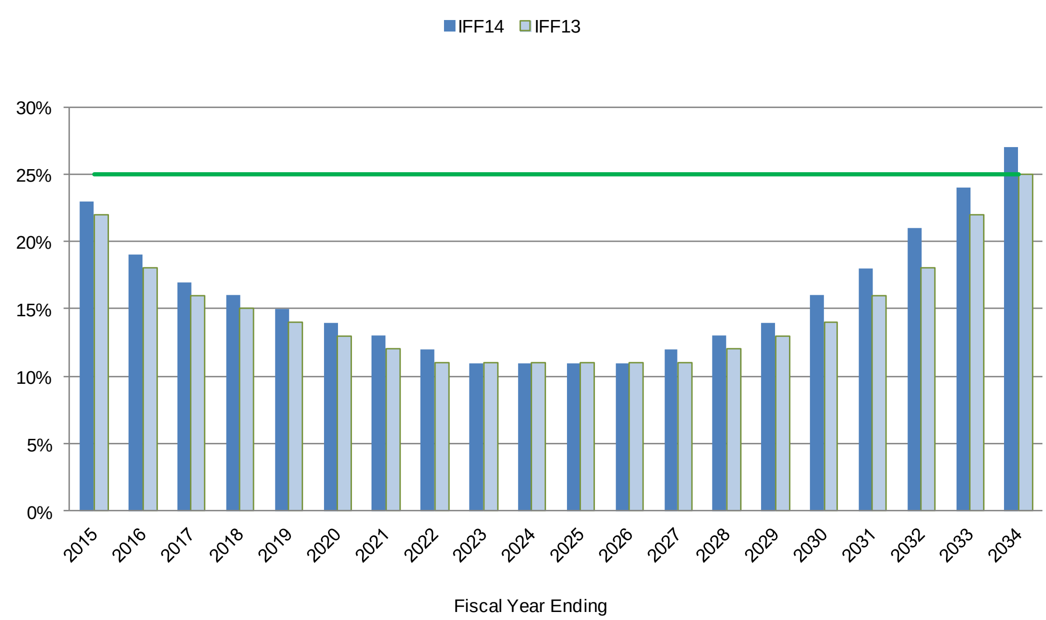
Debt/Equity Ratio	Achieve and maintain a minimum debt/equity ratio of 75:25
Interest Coverage	Maintain an annual gross interest coverage ratio of greater than 1.20
Capital Coverage	Maintain a capital coverage ratio of greater than 1.20 (excepting major new generation and transmission)

Financial targets may not be achieved during years of major investment in the generation and transmission system.

15.1 Debt/Equity Ratio

The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Figure 15-1 below shows the projected consolidated equity ratio for IFF14 compared to IFF13. High levels of capital investment over the next ten years combined with reduced revenues result in deterioration of the equity ratio to 11% by 2022/23. The equity ratio shows improvement following the in-service of Keeyask and is projected to return to the target 25% by the end of the 20-year forecast period in 2033/34 (same year as in IFF13).

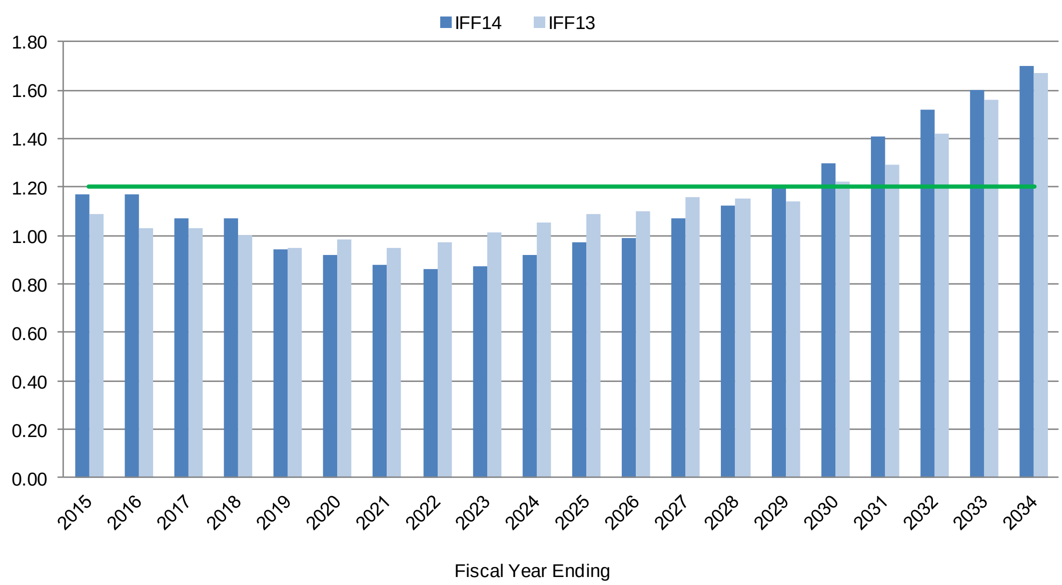
Figure 15-1: Projected Consolidated Equity Ratio



15.2 Interest Coverage Ratio

The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Figure 15-2 below shows that the reduction in net income compared to the previous forecast IFF13 and increase in capital requirements for Bipole III, Keeyask, DSM and to replace aging infrastructure results in interest coverage ratios lower than target for a period of fourteen years. In the longer term, interest coverage is projected to return to the 1.20 target level by 2028/29.

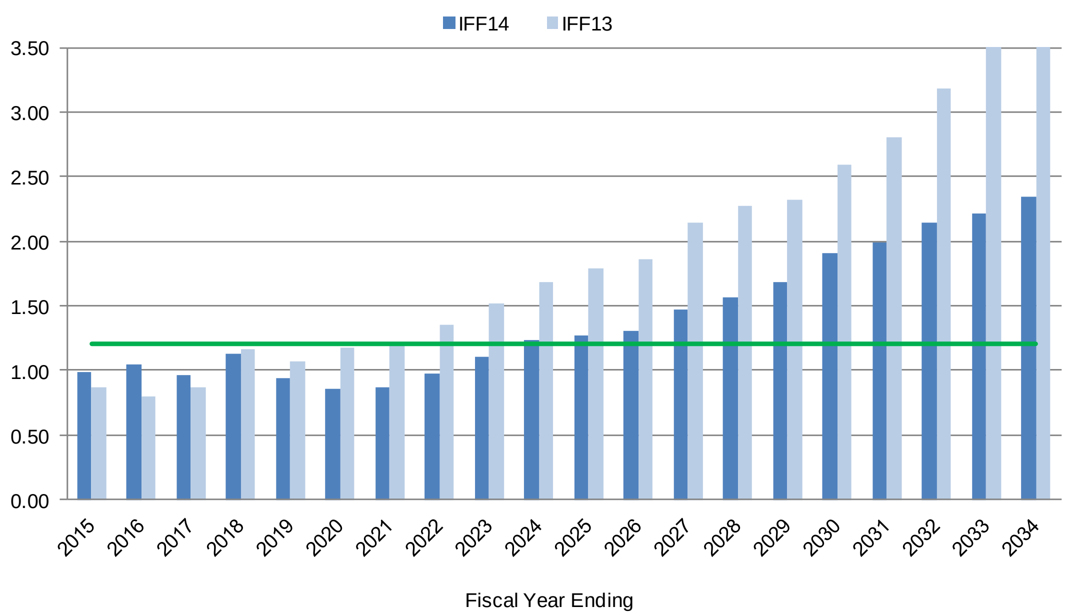
Figure 15-2: Projected Consolidated Interest Coverage Ratio



15.3 Capital Coverage Ratio

The capital coverage ratio measures the ability of current period internally generated funds to finance sustaining capital expenditures (excluding major new generation and related transmission). Figure 15-3 below shows the comparative capital coverage ratios between IFF14 and IFF13. Capital coverage is below target for the first nine years of the forecast due to the reduction in net income and increasing capital requirements to replace aging infrastructure. Thereafter, projected cash flows are sufficient to enable this target to be met in the remaining years of the forecast after the in-service of the Keeyask Generating Station.

Figure 15-3: Projected Consolidated Capital Coverage Ratio



16.0 SENSITIVITY ANALYSIS

The 20-Year Financial Outlook includes a number of key assumptions as described in the previous sections. A change to one or more of those assumptions could have a significant impact on projected financial results. This section provides an indication of the financial impact of changes in the following assumptions:

- Domestic load growth
- Interest rates
- Foreign exchange rates
- Export prices
- Capital expenditures
- Water flow conditions
- Rate Increases

Table 16-1 below shows the change in retained earnings and incremental even annual rate increases/(decreases) required to achieve the same level of retained earnings in 2023/24 as forecast in IFF14.

Table 16-1: Financial Impacts of Sensitivity Analysis

	2016/17	2020/21	2023/24	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Incremental Annual Electric Rate Increase/(Decrease)
Low Domestic Load Growth	(4)	(24)	(32)	0.04%
High Domestic Load Growth	(4)	54	65	-0.08%
+ 1% Interest	(47)	(423)	(1,071)	1.27%
- 1% Interest	45	398	987	-1.31%
C$/US$ Down 0.10 (C$ Strengthening)	5	(3)	(159)	0.20%
C$/US$ Up 0.10 (C$ Weakening)	(5)	3	159	-0.20%
Low Export Price	(44)	(304)	(704)	0.88%
High Export Price	28	245	626	-0.81%
5 Year Drought (starting in 2016/17)	N/A	(1,711)	N/A	2.43%
+ 1% Rate Increase in 2016	31	116	206	-0.26%
- 1% Rate Increase in 2016	(31)	(115)	(200)	0.26%
Capital Down $50 million/year	7	85	206	-0.26%
Capital Up $50 million/year	(7)	(85)	(205)	0.26%

16.1 Domestic Load Growth Sensitivity

The 2014 Electric Load Forecast is prepared with the expectation that there is a 50% chance that actual Manitoba energy requirements could be higher or lower than forecast. To evaluate the potential variation in the load forecast due to long term economic effects, 10% and 90% confidence bands (±1.28 standard deviations) were selected to represent proxies for the low and high load forecast scenarios. The variability in gross firm energy could be ±1 093 GW.h by 2023/24 or ±261 MW in system peak energy.

Historically, domestic load requirements higher than forecast would result in greater adverse financial impacts than lower domestic loads due to the higher value of opportunity export sales compared to domestic revenues. With the weakening of forecast electricity export prices compared to previous forecasts, wholesale market export and domestic retail average rates have inverted and the resulting revenue impacts are positive to Manitoba Hydro over the 10-year forecast. In the high domestic load growth scenario, net income impacts in the near term (to 2019/20) that are greater in absolute terms than the net income impacts under the low domestic load growth scenario. This is due to the availability of Brandon until its decommissioning date in 2019/20 to supply firm Manitoba load (which is not available to supply firm export sales). Brandon would be dispatched before displacing uncommitted firm sales which are limited over this period.

Under low load growth, the reduction to revenues is greater than the increase in export sales resulting in a net reduction to revenues and net income.

16.2 Interest Rates Sensitivity

Interest rates assumed in IFF14 are projected to rise gradually over the first six years of the forecast. The interest rate sensitivity indicates the financial impacts of interest rates one percent higher or lower than forecast on short-term, long-term and floating rate debt, as well as sinking funds.

16.3 Foreign Exchange Rates Sensitivity

The Canadian dollar is projected to be weaken to $1.12 (C$/US$) over the first five years of the forecast and then is projected to slightly strengthen to $1.10 (C$/US$). In the short to medium term of the forecast, net income is relatively neutral to changes in the exchange rate, due to the effective hedge provided by Manitoba Hydro's foreign exchange policy. The exchange rate sensitivity indicates the financial impacts of the C$/US$ exchange rate being 0.10 higher (C$ weakening) or lower (C$ strengthening) than forecast.

16.4 Export Prices Sensitivity

IFF14 reflects the expected electricity export prices derived from several independent price forecasts for the Midwest independent System Operator (MISO) region. Each price forecast consultant has their own electricity price forecast models, assumptions and view of the future. In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These factors include:

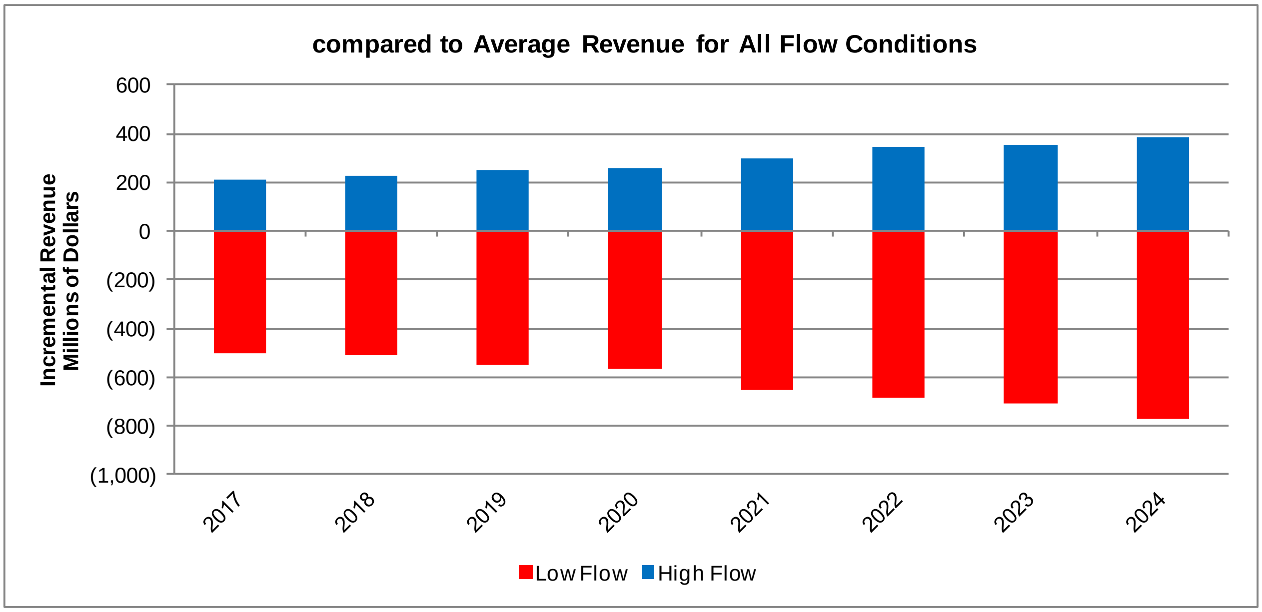
- Thermal fuel forecasts (coal and natural gas);
- Future load growth forecasts;
- Profile of existing generation (fuel type, efficiency and operating parameters);
- Profile of potential new generation (fuel type, efficiency, capital cost and required rates of return);
- Generation requirements;
- Power market rules; and
- Future regulation/legislation related to SO2 (sulfur dioxide), NOX (nitrous oxide), Hg (mercury) and CO2 (carbon dioxide) emissions, as well as cooling water releases and coal ash handling.

There is uncertainty in each of these factors, and particular uncertainty as to how future legislative requirements may evolve. In addition to the expected case, forecast consultants provide high and low price cases with their views of potential long-term lower and higher variations from expected export prices. The export price sensitivities provided in this analysis reflect these low and high export price cases, coupled with low and high natural gas prices.

16.5 Drought/Water Flow Sensitivity

IFF14 reflects the average revenues and expenses of 102 different potential system inflow conditions that occurred historically from 1912/13 to 2013/14. Although the forecast inherently includes the revenues and expenses associated with both the highest and lowest inflow conditions, the actual inflow could vary significantly from forecast in any given year as shown in Figure 16-2. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years.

Figure 16-2: Variability of Net Interchange Revenue



A prolonged period of low flows has a significant financial impact. The current estimate of a recurrence of the historic five-year drought from 1987/88 to 1991/92 is approximately $1.7 billion by the end of the drought period in 2020/21. This represents the deviation in net interchange revenues and generation costs if the five-year drought begins in 2016/17 compared to the average net revenues resulting from all historic flow cases. The costs of drought could rise under a scenario of higher electricity export and thermal fuel prices.

16.6 Rate Increase Sensitivity

Table 16-1 indicates the financial impact of a +/-1% change in the proposed electric rate increase in 2015/16 and demonstrates that required even annual rate increases of 3.95% will increase or decrease by +/- 0.26% over the remaining eight years to 2023/24.

16.7 Capital Expenditure Sensitivity

The capital expenditure sensitivity reflects the financial effects of inflationary or deflationary changes to Major & Base Capital relative to general inflation levels and/or reduction or increases to expenditures necessary to meet reliability, regulatory or customer requirements.

Section 2

17.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF14)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers	1,856	1,935	1,971	2,066	2,145	2,229	2,309	2,395	2,490	2,595
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
	2,235	2,337	2,387	2,487	2,613	2,744	3,125	3,339	3,448	3,582
Cost of Gas Sold	269	277	247	246	246	246	247	248	247	246
	1,965	2,060	2,140	2,241	2,367	2,497	2,878	3,091	3,201	3,336
Other	60	60	62	64	65	66	68	69	71	72
	2,025	2,121	2,203	2,305	2,432	2,563	2,946	3,160	3,272	3,408
EXPENSES										
Operating and Administrative	562	617	628	635	649	664	680	687	701	715
Finance Expense	530	546	585	621	792	928	1,235	1,367	1,376	1,393
Depreciation and Amortization	437	434	455	480	556	560	648	702	771	788
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	119	127	141	155	164	165	166	172	172	183
Other Expenses	29	30	31	32	32	33	34	34	35	36
	1,936	2,007	2,144	2,236	2,512	2,669	3,120	3,353	3,445	3,514
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	115	126	67	75	(75)	(102)	(164)	(192)	(174)	(109)
Additional General Consumers Revenue										
General electricity rate increases	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
General gas rate increases	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Financial Ratios										
Equity	23%	19%	17%	16%	15%	14%	13%	12%	11%	11%
Interest Coverage	1.17	1.17	1.07	1.07	0.94	0.92	0.88	0.86	0.87	0.92
Capital Coverage	0.99	1.05	0.96	1.13	0.94	0.86	0.87	0.98	1.11	1.24

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers	2,703	2,819	2,937	3,062	3,193	3,336	3,485	3,584	3,686	3,792
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
	3,699	3,747	3,881	3,984	4,113	4,263	4,396	4,485	4,569	4,675
Cost of Gas Sold	246	245	245	244	244	244	244	244	245	245
	3,453	3,502	3,636	3,740	3,869	4,019	4,152	4,241	4,324	4,431
Other	74	75	77	78	80	82	83	85	87	89
	3,527	3,577	3,713	3,818	3,949	4,101	4,235	4,326	4,411	4,520
EXPENSES										
Operating and Administrative	729	744	758	773	789	801	815	832	848	865
Finance Expense	1,396	1,394	1,385	1,385	1,370	1,349	1,312	1,247	1,212	1,168
Depreciation and Amortization	803	817	829	843	850	861	871	883	897	914
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	184	185	187	188	189	189	191	193	196	198
Other Expenses	37	37	38	39	40	41	41	42	43	44
	3,560	3,585	3,613	3,644	3,663	3,676	3,672	3,649	3,653	3,659
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(38)	(9)	97	168	279	415	551	662	741	842
Additional General Consumers Revenue										
General electricity rate increases	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
General gas rate increases	0.50%	1.25%	0.50%	1.00%	0.75%	0.75%	0.50%	1.00%	0.75%	1.00%
Financial Ratios										
Equity	11%	11%	12%	13%	14%	16%	18%	21%	24%	27%
Interest Coverage	0.97	0.99	1.07	1.12	1.20	1.30	1.41	1.52	1.60	1.70
Capital Coverage	1.27	1.31	1.47	1.57	1.68	1.91	1.99	2.14	2.22	2.34

CONSOLIDATED PROJECTED BALANCE SHEET (IFF14)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17,860	18,665	19,921	20,809	25,805	29,211	34,113	34,790	35,458	36,157
Accumulated Depreciation	(5,864)	(6,214)	(6,610)	(7,031)	(7,525)	(8,073)	(8,698)	(9,371)	(10,058)	(10,760)
Net Plant in Service	11,997	12,451	13,310	13,778	18,280	21,138	25,415	25,419	25,400	25,397
Construction in Progress	3,261	4,936	6,759	8,986	6,044	3,943	173	189	245	267
Current and Other Assets	1,350	1,093	1,317	1,744	1,742	2,045	2,277	1,667	1,608	1,810
Goodwill and Intangible Assets	270	258	246	236	236	246	237	221	206	190
Regulated Assets	340	362	398	434	475	495	506	501	484	464
	17,218	19,100	22,030	25,177	26,777	27,867	28,608	27,997	27,942	28,129
LIABILITIES AND EQUITY										
Long-Term Debt	11,722	13,825	16,698	18,706	21,194	21,923	22,809	22,972	23,267	23,458
Current and Other Liabilities	2,086	2,202	2,121	3,053	2,141	2,558	2,590	2,022	1,803	1,855
Contributions in Aid of Construction	436	489	537	587	639	690	740	791	842	894
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2,831	2,901	2,968	3,043	2,968	2,866	2,702	2,510	2,336	2,226
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	17,218	19,100	22,030	25,177	26,777	27,867	28,608	27,997	27,942	28,129
Equity Ratio	23%	19%	17%	16%	15%	14%	13%	12%	11%	11%

CONSOLIDATED PROJECTED BALANCE SHEET (IFF14)
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	36,877	37,639	38,546	39,301	40,080	40,813	41,592	42,389	43,204	44,376
Accumulated Depreciation	(11,478)	(12,211)	(12,960)	(13,728)	(14,510)	(15,303)	(16,110)	(16,933)	(17,773)	(18,629)
Net Plant in Service	25,399	25,428	25,585	25,573	25,570	25,510	25,482	25,456	25,431	25,747
Construction in Progress	326	348	229	258	281	327	369	406	469	259
Current and Other Assets	1,746	2,061	2,354	2,540	2,970	3,321	3,171	3,826	4,496	5,233
Goodwill and Intangible Assets	176	161	148	137	125	114	103	91	80	68
Regulated Assets	438	415	393	367	350	341	336	336	343	347
	28,084	28,413	28,709	28,875	29,295	29,612	29,461	30,116	30,819	31,655
LIABILITIES AND EQUITY										
Long-Term Debt	23,412	24,215	24,418	24,360	24,493	23,766	23,757	23,760	23,754	23,398
Current and Other Liabilities	1,842	1,323	1,267	1,268	1,223	1,797	1,050	984	896	1,189
Contributions in Aid of Construction	947	1,000	1,052	1,105	1,159	1,213	1,268	1,323	1,380	1,437
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2,188	2,179	2,276	2,444	2,724	3,139	3,690	4,352	5,093	5,935
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	28,084	28,413	28,709	28,875	29,295	29,612	29,461	30,116	30,819	31,655
Equity Ratio	11%	11%	12%	13%	14%	16%	18%	21%	24%	27%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	2,368	2,473	2,526	2,631	2,729	2,851	3,234	3,449	3,560	3,696
Cash Paid to Suppliers and Employees	(1,243)	(1,281)	(1,346)	(1,386)	(1,415)	(1,433)	(1,490)	(1,522)	(1,549)	(1,584)
Interest Paid	(528)	(532)	(565)	(613)	(804)	(949)	(1,243)	(1,371)	(1,352)	(1,365)
Interest Received	13	15	21	30	35	34	31	28	15	16
	610	675	636	662	545	503	532	584	674	763
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,983	2,400	3,200	3,200	2,800	1,600	1,600	600	600	600
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(835)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(461)	(300)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,213	2,087	2,846	2,857	2,023	1,470	943	573	263	295
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,951)	(2,586)	(3,187)	(3,281)	(2,289)	(1,588)	(1,050)	(799)	(743)	(741)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(22)	(21)	(21)	(21)	(22)	(36)	(30)	(30)	(30)	(30)
	(2,097)	(2,809)	(3,376)	(3,545)	(2,551)	(1,869)	(1,343)	(1,187)	(1,026)	(1,030)
Net Increase (Decrease) in Cash	(275)	(47)	106	(27)	16	104	132	(30)	(89)	28
Cash at Beginning of Year	142	(133)	(179)	(73)	(100)	(83)	20	152	122	33
Cash at End of Year	(133)	(179)	(73)	(100)	(83)	20	152	122	33	61

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF14)
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,815	3,865	4,001	4,105	4,237	4,389	4,524	4,615	4,701	4,810
Cash Paid to Suppliers and Employees	(1,610)	(1,623)	(1,648)	(1,665)	(1,690)	(1,715)	(1,738)	(1,767)	(1,790)	(1,822)
Interest Paid	(1,373)	(1,379)	(1,380)	(1,399)	(1,396)	(1,390)	(1,371)	(1,282)	(1,263)	(1,233)
Interest Received	19	21	35	49	62	71	84	63	78	92
	851	884	1,008	1,090	1,213	1,355	1,499	1,630	1,726	1,848
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	400	800	200	-	200	-	-	-	-	-
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(100)	(700)	(13)	(30)	-
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	264	423	171	(27)	175	(22)	(21)	(38)	(37)	(36)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(793)	(801)	(803)	(792)	(811)	(794)	(837)	(852)	(899)	(981)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(31)	(31)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)
	(1,094)	(1,101)	(1,106)	(1,109)	(1,140)	(1,134)	(1,184)	(1,177)	(1,235)	(1,329)
Net Increase (Decrease) in Cash	21	206	73	(45)	247	200	293	415	454	483
Cash at Beginning of Year	61	82	288	361	316	563	763	1,056	1,471	1,925
Cash at End of Year	82	288	361	316	563	763	1,056	1,471	1,925	2,408

18.0 CAPITAL EXPENDITURE FORECAST (CEF14)

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1,448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6,496.1	776.3	676.3	962.2	1,351.3	927.9	616.5	208.6	55.2	4.5	0.1	5,578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1,852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GRE	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1,655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1,514.0
Bipole III - Converter Stations	2,675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2,356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1,451.7**	**1,913.9**	**2,463.5**	**2,577.8**	**1,530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11,670.7**
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	7.2	0.7	14.0	26.4	29.6	40.9	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	2.7	2.7
Slave Falls Major Overhauls	126.1	-	-	-	-	-	2.5	2.4	19.4	18.8	19.9	63.0
Pointe du Bois GS Rehabilitation	182.9	10.1	15.4	47.0	50.0	25.2	9.8	11.2	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	15.8	14.2	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	6.0	0.4	17.5	7.8	18.8	50.4
Base Capital	NA	98.9	101.6	71.0	55.7	77.2	72.7	118.1	97.8	110.7	98.7	902.4
Generation Operations Total	**NA**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1,336.1**
Transmission												
Rockwood East 230/115kV Station	53.3	26.6	11.1	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	14.2	35.8	8.2	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	1.3	3.7	37.0	13.9	1.6	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	1.0	8.6	8.8	8.9	23.3	23.7	24.2	24.7	27.9	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishm	73.3	8.7	8.5	2.7	5.2	2.2	2.3	2.4	2.7	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	2.1	13.2	22.9	56.9	57.9	59.0	21.8	233.7
Base Capital	NA	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63.0	128.2	777.0
Transmission Total	**NA**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1,350.0**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major & Base Capital												
Electric												
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	32.6	33.6	12.8	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	0.3	3.0	20.0	20.0	7.9	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	2.4	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	0.7	21.2	22.9	8.8	5.0	3.4	-	-	-	-	62.0
Base Capital	NA	197.0	182.6	209.6	160.7	173.0	193.3	206.0	210.1	214.3	218.6	1,965.3
Customer Service & Distribution Total	**NA**	**235.5**	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2,211.8**
Customer Care & Energy Conservation	**NA**	**3.2**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services	**NA**	**75.0**	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
		570.9	**577.0**	**584.6**	**522.3**	**522.4**	**522.5**	**547.6**	**554.7**	**562.8**	**571.0**	**5,535.9**
Gas												
Customer Service & Distribution	**NA**	**34.9**	**49.0**	**34.9**	**22.3**	**21.2**	**24.4**	**26.1**	**27.7**	**30.0**	**28.3**	**298.8**
Customer Care & Energy Conservation	**NA**	**3.4**	**5.4**	**4.6**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**	**5.2**	**5.3**	**48.1**
Gas Demand Side Management	**NA**	**9.6**	**10.4**	**11.0**	**9.4**	**8.7**	**8.9**	**8.9**	**9.3**	**9.5**	**9.9**	**95.5**
		48.0	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**
Major & Base Capital Target Adjustment	NA	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**618.9**	**641.9**	**660.1**	**583.7**	**582.1**	**585.6**	**612.6**	**596.7**	**607.5**	**614.4**	**6,103.4**
CONSOLIDATED CEF14 TOTAL		**2,070.6**	**2,555.8**	**3,123.6**	**3,161.5**	**2,113.0**	**1,469.6**	**1,038.7**	**792.8**	**724.1**	**724.4**	**17,774.1**
ELECTRIC CAPITAL TOTAL		**2,022.6**	**2,490.9**	**3,073.1**	**3,125.2**	**2,078.3**	**1,431.5**	**998.8**	**750.8**	**679.4**	**681.0**	**17,331.7**
GAS CAPITAL TOTAL		**48.0**	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1,448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6,496.1	-	-	-	-	-	-	-	-	-	-	5,578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1,852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GRE	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1,655.4	-	-	-	-	-	-	-	-	-	-	1,514.0
Bipole III - Converter Stations	2,675.1	-	-	-	-	-	-	-	-	-	-	2,356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1,186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12,611.1**
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	-	115.9
Slave Falls Major Overhauls	126.1	20.1	21.3	20.9	0.9	-	-	-	-	-	-	126.1
Pointe du Bois GS Rehabilitation	182.9	-	-	-	-	-	-	-	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Base Capital	NA	119.9	103.0	106.0	127.5	153.4	112.3	164.3	163.5	167.4	170.8	2,290.6
Generation Operations Total	**NA**	**142.9**	**145.7**	**148.7**	**151.6**	**154.7**	**157.8**	**160.9**	**164.1**	**167.4**	**170.8**	**2,900.6**
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishm	73.3	-	-	-	-	-	-	-	-	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	-	-	-	-	-	233.7
Base Capital	NA	153.0	156.1	159.2	162.4	165.6	168.9	172.3	175.7	179.3	182.8	2,452.3
Transmission Total	**NA**	**153.0**	**156.1**	**159.2**	**162.4**	**165.6**	**168.9**	**172.3**	**175.7**	**179.3**	**182.8**	**3,025.3**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major & Base Capital												
Electric												
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	-	-	-	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	-	-	-	-	-	-	-	-	-	-	62.0
Base Capital	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	4,773.2
Customer Service & Distribution Total	**NA**	**261.6**	**257.8**	**263.3**	**267.2**	**285.6**	**268.1**	**298.7**	**297.6**	**302.6**	**305.3**	**5,019.6**
Customer Care & Energy Conservation	**NA**	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**81.0**
Human Resources & Corporate Services	**NA**	**59.5**	**60.7**	**61.9**	**63.2**	**64.4**	**65.7**	**67.0**	**68.4**	**69.8**	**71.1**	**1,248.6**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**4.9**
		621.1	**624.5**	**637.3**	**648.6**	**674.7**	**665.0**	**703.5**	**710.5**	**723.8**	**734.9**	**12,279.9**
Gas												
Customer Service & Distribution	**NA**	**33.7**	**33.5**	**34.0**	**34.7**	**36.6**	**34.1**	**38.2**	**39.3**	**40.2**	**41.0**	**664.1**
Customer Care & Energy Conservation	**NA**	**5.4**	**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**106.8**
Gas Demand Side Management	**NA**	**9.6**	**9.8**	**10.0**	**5.7**	**5.7**	**5.8**	**5.8**	**5.9**	**6.0**	**6.1**	**165.9**
		48.7	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**
Major & Base Capital Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**669.8**	**673.2**	**686.9**	**694.7**	**722.8**	**710.8**	**753.6**	**761.9**	**776.3**	**788.4**	**13,341.7**
CONSOLIDATED CEF14 TOTAL		**777.6**	**783.9**	**784.7**	**776.0**	**793.3**	**771.5**	**820.1**	**833.5**	**874.7**	**963.4**	**25,952.9**
ELECTRIC CAPITAL TOTAL		**728.9**	**735.1**	**735.1**	**729.9**	**745.3**	**725.7**	**770.0**	**782.2**	**822.2**	**910.0**	**25,016.1**
GAS CAPITAL TOTAL		**48.7**	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**

19.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH14)

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1,437	1,454	1,460	1,483	1,490	1,501	1,506	1,513	1,525	1,538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1,831	1,928	2,008	2,101	2,222	2,352	2,732	2,944	3,054	3,182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1,194	1,326	1,334	1,349
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1,754	1,824	1,956	2,044	2,317	2,471	2,920	3,150	3,239	3,304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1,551	1,565	1,580	1,593	1,607	1,624	1,641	1,659	1,677	1,696
additional*	734	832	935	1,043	1,157	1,280	1,409	1,486	1,566	1,649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3,298	3,342	3,475	3,575	3,702	3,849	3,980	4,065	4,145	4,248
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1,351	1,348	1,338	1,337	1,321	1,301	1,263	1,197	1,161	1,116
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3,346	3,365	3,388	3,415	3,430	3,439	3,432	3,403	3,403	3,404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17,163	17,912	19,127	19,988	24,957	28,333	33,202	33,846	34,478	35,142
Accumulated Depreciation	(5,676)	(6,012)	(6,392)	(6,795)	(7,270)	(7,798)	(8,403)	(9,055)	(9,721)	(10,401)
Net Plant in Service	11,487	11,900	12,735	13,193	17,687	20,535	24,800	24,791	24,757	24,741
Construction in Progress	3,257	4,932	6,755	8,982	6,040	3,939	169	185	241	263
Current and Other Assets	1,798	1,570	1,822	2,268	2,295	2,598	2,727	2,167	2,238	2,442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16,993	18,866	21,801	24,961	26,585	27,668	28,299	27,727	27,788	27,965
LIABILITIES AND EQUITY										
Long-Term Debt	11,705	13,808	16,681	18,689	21,177	21,906	22,792	22,955	23,250	23,441
Current and Other Liabilities	2,016	2,151	2,097	3,069	2,214	2,654	2,604	2,104	2,028	2,101
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2,717	2,778	2,837	2,902	2,812	2,696	2,518	2,312	2,126	2,001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16,993	18,866	21,801	24,961	26,585	27,668	28,299	27,727	27,788	27,965

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35,822	36,544	37,410	38,124	38,859	39,555	40,294	41,050	41,823	42,952
Accumulated Depreciation	(11,096)	(11,807)	(12,532)	(13,274)	(14,030)	(14,800)	(15,585)	(16,384)	(17,200)	(18,031)
Net Plant in Service	24,725	24,737	24,878	24,849	24,828	24,754	24,710	24,666	24,623	24,921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2,387	2,536	2,801	3,049	3,421	3,773	3,629	4,288	4,963	5,703
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27,914	28,063	28,316	28,533	28,884	29,191	29,030	29,675	30,366	31,189
LIABILITIES AND EQUITY										
Long-Term Debt	23,395	24,198	24,401	24,343	24,476	23,749	23,739	23,743	23,737	23,381
Current and Other Liabilities	2,112	1,443	1,373	1,456	1,372	1,968	1,243	1,199	1,132	1,446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1,029	1,069	1,109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1,948	1,924	2,007	2,161	2,427	2,826	3,361	4,008	4,732	5,557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27,914	28,063	28,316	28,533	28,884	29,191	29,030	29,675	30,366	31,189

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,859	1,958	2,039	2,134	2,231	2,349	2,729	2,941	3,051	3,180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1,000)	(1,015)	(1,069)	(1,099)	(1,124)	(1,155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1,222)	(1,349)	(1,329)	(1,341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,953	2,390	3,190	3,200	2,790	1,600	1,590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1,195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1,218	2,077	2,836	2,857	2,013	1,470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1,900)	(2,518)	(3,134)	(3,244)	(2,253)	(1,550)	(1,010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2,046)	(2,742)	(3,323)	(3,508)	(2,516)	(1,830)	(1,302)	(1,144)	(980)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,295	3,340	3,472	3,572	3,699	3,846	3,977	4,062	4,142	4,245
Cash Paid to Suppliers and Employees	(1,179)	(1,189)	(1,211)	(1,225)	(1,247)	(1,269)	(1,288)	(1,314)	(1,334)	(1,363)
Interest Paid	(1,348)	(1,353)	(1,354)	(1,371)	(1,368)	(1,360)	(1,341)	(1,250)	(1,230)	(1,200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1,024	1,146	1,288	1,432	1,561	1,655	1,775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	403	161	(37)	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,045)	(1,051)	(1,056)	(1,062)	(1,091)	(1,087)	(1,134)	(1,125)	(1,182)	(1,275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1,390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1,390	1,844

20.0 GAS OPERATIONS FINANCIAL FORECAST (CGM14)

GAS OPERATIONS (CGM14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
REVENUES										
General Consumers										
at approved rates	419	423	393	394	398	399	401	402	402	402
additional revenue requirement*	0	0	0	7	8	8	8	8	8	14
	419	423	393	401	405	407	409	410	410	416
Cost of Gas Sold	270	277	247	247	246	247	247	248	247	247
Gross Margin	149	147	146	154	159	160	161	162	162	169
Other	1	2	2	2	2	2	2	2	2	2
	151	148	148	156	161	162	163	164	164	171
EXPENSES										
Operating and Administrative	68	67	68	69	69	70	71	71	73	74
Finance Expense	16	17	19	21	21	22	22	23	24	25
Depreciation and Amortization	29	29	29	31	31	32	32	33	33	34
Capital and Other Taxes	19	19	20	20	20	20	21	21	21	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	144	144	148	152	154	157	157	160	162	167
Net Income	7	4	0	3	7	5	6	4	2	4
* Additional Revenue Requirement										
Percent Increase	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.75%
Cumulative Percent Increase	0.00%	0.00%	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	3.79%

GAS OPERATIONS (CGM14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	716	765	800	823	846	872	899	929	960	990
Accumulated Depreciation	(248)	(256)	(267)	(279)	(292)	(306)	(320)	(335)	(351)	(368)
Net Plant in Service	468	509	533	544	554	566	579	594	609	623
Construction in Progress	4	4	4	4	4	4	4	4	4	4
Current and Other Assets	120	121	121	121	121	121	121	121	121	121
Goodwill and Intangible Assets	7	6	6	5	5	4	4	4	4	4
Regulated Assets	85	84	85	82	78	75	72	70	68	66
	684	723	748	756	762	770	780	792	806	817
LIABILITIES AND EQUITY										
Long-Term Debt	300	310	320	320	330	330	340	320	350	370
Current and Other Liabilities	130	137	137	126	97	84	64	76	43	15
Contributions in Aid of Construction	64	83	98	114	131	148	163	178	193	208
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	69	72	72	75	82	87	93	97	99	102
	684	723	748	756	762	770	780	792	806	817

GAS OPERATIONS (CGM14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	457	461	430	438	439	441	443	445	444	451
Cash Paid to Suppliers and Employees	(413)	(380)	(373)	(382)	(384)	(386)	(388)	(390)	(391)	(393)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(25)
	25	61	37	35	34	33	33	32	29	33
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	30	10	10	-	10	-	10	-	40	20
Retirement of Long-Term Debt	(35)	-	-	-	-	-	-	-	(20)	(10)
Other	-	-	-	-	-	-	-	-	-	-
	(5)	10	10	-	10	-	10	-	20	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(50)	(66)	(52)	(37)	(35)	(39)	(40)	(42)	(45)	(44)
Other	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(50)	(66)	(52)	(37)	(36)	(39)	(41)	(43)	(46)	(44)
Net Increase (Decrease) in Cash	(30)	6	(4)	(2)	8	(6)	2	(11)	4	(1)
Cash at Beginning of Year	(34)	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)
Cash at End of Year	(64)	(59)	(63)	(65)	(57)	(63)	(61)	(72)	(68)	(69)

21.0 CORPORATE SUBSIDIARIES FINANCIAL FORECAST (CS14)

CORPORATE SUBSIDIARIES (CS14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
Revenue	53	55	57	58	59	60	62	63	64	66
Cost of Operations	29	30	31	32	32	33	34	35	35	36
	23	24	26	26	27	27	28	29	29	30
EXPENSES										
Operating and Administrative	15	16	16	16	17	17	17	17	17	18
Finance Expense	(0)	(0)	(0)	-	-	-	-	-	-	-
Depreciation and Amortization	1	2	2	2	2	2	1	1	1	0
Capital and Other Taxes	1	1	1	1	1	1	1	1	1	1
	17	18	19	19	19	19	19	19	19	19
Net Income	6	6	7	8	8	8	9	9	10	11

CORPORATE SUBSIDIARIES (CS14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	16	17	19	19	19	19	19	19	19	19
Accumulated Depreciation	(5)	(7)	(9)	(10)	(12)	(13)	(15)	(16)	(17)	(17)
Net Plant in Service	10	10	10	8	7	5	4	2	2	2
Construction in Progress	-	-	-	-	-	-	-	-	-	-
Current and Other Assets	44	50	58	67	76	86	97	108	119	130
Goodwill and Intangible Assets	1	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Regulated Assets	0	0	0	0	0	0	0	0	0	0
	54	61	68	75	83	92	101	110	120	132
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Current and Other Liabilities	7	7	7	7	7	7	7	7	7	7
Contributions in Aid of Construction	0	0	0	0	0	0	0	0	0	0
Share Captial	1	1	1	1	1	1	1	1	1	1
Retained Earnings	46	52	59	67	74	83	92	101	112	123
	54	61	68	75	83	92	101	110	120	132

CORPORATE SUBSIDIARIES (CS14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	53	55	57	58	59	60	62	63	64	66
Cash Paid to Suppliers and Employees	(45)	(47)	(48)	(49)	(50)	(51)	(51)	(52)	(53)	(54)
Interest Paid	0	0	0	-	-	-	-	-	-	-
	7	8	9	9	10	10	10	11	11	11
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1)	(2)	(1)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(1)	(2)	(1)	-	-	-	-	-	-	-
Net Increase (Decrease) in Cash	6	6	8	9	10	10	10	11	11	11
Cash at Beginning of Year	9	15	21	29	38	48	58	68	79	90
Cash at End of Year	15	21	29	38	48	58	68	79	90	101